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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Enhance the
Role of Demand Response in Meeting the
State's Resource Planning Needs and
Operational Requirements.

Rulemaking 13-09-011

**COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION
SUPPORTING ADOPTION, WITH MODIFICATIONS AND CLARIFICATIONS, OF
ADMINISTRATIVE LAW JUDGE HYMES' PROPOSED DECISION**

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Subject Index of Proposed Changes

The PD should be revised to clarify that the utilities may propose replacement programs for the Demand Bidding Program in their December 31, 2016 Applications for Demand Response Portfolios for existing programs and activities.

The PD should be revised to ensure sufficient budgetary flexibility for PG&E to fund a replacement program for DBP, as PG&E's 2017 bridge funding does not include funds for DBP.

The PD's discussion of prohibited resources should be clarified.

The PD's description of CLECA's position on education efforts for time of use rates should be corrected.

The PD's discussion of the Demand Response Auction Mechanism should address the issues raised by CLECA regarding the risk of gaming and concerns regarding bid viability associated with longer contract terms.

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Pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, the California Large Energy Consumers Association (CLECA) submits these comments on the Proposed Decision (PD) of Administrative Law Judge Hymes. CLECA supports adoption of the PD with the modifications and clarifications discussed below.

I. INTRODUCTION

Demand response remains in a state of flux and transition. Data do not yet exist on the market performance of resources procured through the Demand Response Auction Mechanism (DRAM) pilot, and work remains to be done on the full integration of the investor owned utilities' programs. The California Independent System Operator's (CAISO) wholesale market rules applicable to supply-side demand response continue to change, as do the Commission's regulatory policies applicable to all resources, including demand response (*e.g.*, resource adequacy). Persistent efforts by almost all parties toward full bifurcation must be recognized, but we are not there yet.

CLECA accordingly supports the PD's determination to delay development of "advanced demand response" to ensure that our nascent market experience can inform that development while allowing for existing demand response programs to continue. Care must be taken, however, to not risk losing existing, proven industrial customer demand response during this tumultuous transition.¹ The ability to participate in cost-effective demand response programs and offer proven, valuable load reduction and load shifting in exchange for reasonable incentives can help keep industry in California, where the power is cleaner and greener. Demand response is more than a tool to help integrate renewable resources and stabilize the grid; its impacts are broader. The PD's primary goal for Commission-regulated demand response programs is that they "shall assist the State in meeting its environmental objectives, cost-effectively meet the needs of the grid, and enable customers to meet their energy needs at a reduced cost."² CLECA supports this overarching goal. The impacts on industrial customers of demand response programs, particularly in connection with this goal, should be a top priority as the Commission continues to forge the future of demand response.

II. THE PD SHOULD BE ADOPTED WITH MODIFICATIONS AND CLARIFICATIONS

A. The PD Should Be Clarified to Permit a Replacement for the Demand Bidding Program and the 2017 Budget Cap on the 2018 IOU Programs Should Be a Soft Cap and Permit DBP Replacement Funding for PG&E

The PD orders "Demand response programs implemented by the Utilities shall not participate in the auction mechanism and shall be capped at the 2017 budget levels

¹ These comments are not meant to indicate lack of support for residential, commercial, and agricultural demand response. Demand response from all types of customers is valuable.

² PD, at 42.

until the mid-cycle program review.”³ The mid-cycle review will occur in 2020. PG&E’s Demand Bidding Program (DBP) will be discontinued in 2017, with no budget provided for a replacement program.⁴ While “all new demand response shall be sourced through the auction mechanism,”⁵ the utilities are prohibited from participating in the auction mechanism.⁶ This appears to mean that the utilities cannot develop new demand response programs to replace existing ones before the October 2018 applications. The PD is not clear on whether or how these determinations would permit timely development of a replacement program for DBP, which PG&E triggered five times in June and six times in July so far this summer.⁷

Many of the DBP customers dually participate with the Base Interruptible Program (BIP), which has led to discounting the load impacts of DBP even though it has historically provided hundreds of MW of load reduction. The dual participation rules have not historically allowed counting for cost-effectiveness purposes of the megawatts of DBP load which also participate in BIP,⁸ although D.15-11-042 has initiated some changes to correct for this problem. This is why the DBP historical load impacts have appeared small, not DBP’s program design.⁹ If PG&E is unable to develop a program to replace DBP, then active demand response participants will lose the opportunity to

³ PD, at 90, Ordering Paragraph 13.

⁴ D.16-06-029, at 80 (“It is reasonable to authorize the elimination of the demand bidding program for PG&E and SDG&E in 2017 and for SCE in 2018”).

⁵ PD, at 63.

⁶ PD, at 63.

⁷ See PG&E Monthly Report on Interruptible Load and Demand Response Programs for July 2016 (available online at <http://www.cpuc.ca.gov/general.aspx?id=9922>).

⁸ See D.15-11-042, at 53.

⁹ Decision 16-06-029 unfortunately disregarded CLECA’s clarification regarding DBP’s historical performance due to the dual participation rules. See Comments of the California Large Energy Consumers Association on Proposed Decision Adopting Bridge Funding for 2017 Demand Response Programs and Activities, filed May 23, 2016, at 2.

provide price-based demand response, and consequently lose experience with such participation.

Should the expectation be that PG&E's DBP cannot be replaced? What about SCE's DBP? SCE's DBP will continue in 2017 due to Aliso Canyon, but SCE's program will end in 2018.¹⁰ Between June 20 and July 29, SCE triggered ten DBP events, with 61.3 MW load drops for the first four events, a range of 101.2 MW to 116.6 MW for the next five events, and 99.8 MW drop on the last event day.¹¹ A discontinuation of DBP without any replacement program would be an unfortunate, significant loss of industrial demand response. Critically, the demand response incentives earned by industrial customers help to alleviate some of the pressure from the high cost of power in California caused by the state's energy and carbon policies. This supports keeping production and manufacturing facilities in California, where power is cleaner and greener, rather than such facilities moving to non-California sites with less expensive but more carbon-intensive power. Demand response programs, specifically including DBP, help retain industries, particularly those that are energy-intensive, in California; this aligns with the State's overarching climate goals and should be encouraged by the Commission.

Should the expectation be that DBP would be replaced with a new program to be developed for the October 2018 applications and which would not begin until 2020? That would leave a significant gap for industrial customers who currently actively participate in demand response, offering different products in compliance with the

¹⁰ D.16-06-029, at 80.

¹¹ See SCE Monthly Report on Interruptible Load and Demand Response Programs for July 2016 (available online at <http://www.cpuc.ca.gov/general.aspx?id=9922>). Notably, the last four event days for this voluntary program occurred on four consecutive days.

current dual participation rules. This would be unfortunate as the Commission seeks to expand demand response participation.

The PD should be revised to explicitly state that the IOUs should propose replacement programs for DBP with comparable budgets in their December 31, 2016 applications for 2018 Demand Response Portfolios for existing programs and activities. The PD cites focus on the customer as a key principle, explaining that customer-oriented demand response:

shall ensure that customers of demand response programs have a right to choose from all available products – whether those products be utility programs or third-party programs, are fairly compensated, and are empowered through education.¹²

CLECA completely agrees; customers should be able to choose their demand response provider and be able to participate in a variety of programs pursuant to rational dual participation rules. The PD's discussion of the December 31, 2016 utility filings and the 2017 budget cap should be revised to ensure customers remain able to choose a price-responsive program as a successor to DBP from their utility.

B. The PD's Discussion of the Demand Response Auction Mechanism Should Be Clarified

The PD states that "the size of new demand response sourced through the auction mechanism shall reflect the competitiveness of the bids as described below."¹³ It is not clear what this means. By "size," does the PD mean the total amount procured through the auction mechanism? If not, what does it mean? The PD's "size" discussion warrants clarification.

¹² PD, at 46.

¹³ PD, at 63; see *also* PD at 68 ("the size of the mechanism should be flexible based on the competitiveness of the bids received").

The PD also directs utility acceptance of “all complying bids up to the simple average August capacity bid price” up to “one gigawatt statewide annually” while allowing rejection of bids “priced above the long term avoided cost of generation at the time of the auction.”¹⁴ The discussion in the PD should be expanded to explain more fully what it means. Does the simple average August capacity bid price include all bids, even those well above the long term avoided cost of generation? A simple average could be very high with no cap on the bid prices and would be subject to gaming risk. The potential for gaming risk should be addressed in the revised PD.

The PD also would allow longer DRAM contract terms, of up to five years.¹⁵ CLECA raised potential viability concerns associated with longer contracts due to possible use of bid-to-win strategies, where the prices bid were not expected to be sustainable by the bidder; these are real ratepayer concerns based on experience with the Renewable Portfolio Standard contracts and the multiple price-re-openers permitted in that context.¹⁶ Notably, at an August Demand Response Working Group meeting, one stakeholder indicated that he had indeed recommended such a “bid-to-win” strategy in the DRAM pilot. The PD should consider and address these ratepayer concerns regarding bid viability associated with longer-term contracts; they are not directly resolved with the proposed penalties associated with the Resource Adequacy Availability Incentive Mechanism (RAAIM).

The PD adopts criteria for a review of the DRAM pilot and establishes a process for the Energy Division to “conduct an independent analysis of the results of the 2015

¹⁴ PD, at 68.

¹⁵ PD, at 66.

¹⁶ Comments of the California Large Energy Consumers Association Responding to ALJ Hymes’ Ruling of May 20, 2016, at 15-16.

and 2016 pilot auctions”.¹⁷ The Energy Division is to hold a workshop no later than January 31, 2017 to “present the metrics and evaluation plan.”¹⁸ In connection with the evaluation of the pilot, CLECA recommended including a breakdown of number of customers by customer class and total megawatts by customer class for each month procured by the DRAM.¹⁹ The PD should be revised to require the Energy Division to include this information in particular in its metrics and evaluation plan.

The PD requires the utilities to “complete the efforts of bifurcation and CAISO integration.”²⁰ The utilities, and many other parties including CLECA, have worked very hard to meet the Commission’s bifurcation deadline; however, the January 1, 2018 deadline was rightly conditioned on CAISO integration being feasible and all necessary market changes being made.²¹ As stated above, we are not there yet and it is not just the utilities that have further work to do. Numerous issues at the CAISO have arisen with the integration effort that has occurred to date. These include issues with commitment costs for demand response resources, incorrect settlements, changing subLAPs, local Resource Adequacy requirements, challenges with RAIM for weather-sensitive DR, inability to derate, and telemetry. Among these and other integration matters, the CAISO is also still working on:

- implementation of its Demand Response Registration System (DRRS),

¹⁷ PD, at 61-62.

¹⁸ PD, at 62.

¹⁹ Comments of the California Large Energy Consumers Association Responding to ALJ Hymes’ Ruling of May 20, 2016, at 18.

²⁰ PD, at 59.

²¹ See D.14-12-024, at 74 (Finding of Fact 23: “Full bifurcation of demand response includes 1) adoption and implementation of an appropriate methodology to value and account for load modifying resources; 2) adoption of rules regarding the resource adequacy treatment for demand response resources; **3) adoption and implementation of requirements to integrate demand response into the CAISO market**; and 4) adoption of the categorization of demand response programs.”) (emphasis added).

- changes to the use limit outage reached card for Demand Response resources in connection with the Reliability Services Initiative 1,
- issues with provisional dispatch of some demand response resources in the Residual Unit Commitment process,
- issues with bid insertions of Proxy Demand Response in the real-time market (which is not supposed to occur), and
- additional baseline methodologies.

It is also unclear if there will be sufficient Rule 24 registrations available; these issues should not be glossed over by the PD.

C. The Discussion of Prohibited Resources Should Also Be Clarified

First, CLECA supports the PD's proposal for customers to have "a choice of either signing an attestation to never use prohibited resources during a demand response event or accept a default adjustment."²² CLECA agrees with the PD that this balances "fairness ... with assurances to the Commission."²³ The PD states that if non-residential customers "are required to use a prohibited resource for non-demand response operational reasons, a default adjustment shall be implemented."²⁴ CLECA appreciates the inclusion of the default adjustment. This aspect of the PD should not be changed.

The PD's discussion of bottoming cycle Combined Heat and Power, however, should be revised as follows to more accurately describe it:

whereas in a bottoming-cycle CHP facility, the heat is produced first by or as part of ~~and applied to~~ an industrial process, and then lower-grade waste heat from that industrial process is captured and used to generate electricity.²⁵

²² PD, at 31.

²³ *Id.*

²⁴ PD, at 36.

²⁵ PD, at 29.

D. The PD Should Be Corrected to Reflect CLECA's Urging of Education on Time of Use Rates and that CLECA Did Not Downplay Education

The PD characterizes CLECA's position as "downplaying the education efforts," and states that CLECA believes "customers will respond to rates as they do, with or without education."²⁶ CLECA's position was misunderstood and it has been mischaracterized; the PD should be corrected to accurately reflect the record. CLECA's full statement is:

If load-modifying DR refers to rate design, it is not clear how a goal can be set. Customers will respond to rates as they do. It is hoped that through education they will respond better to price signals, but there is no way to make them respond. CLECA would not support mandatory controls.²⁷

The point is that while the Commission cannot force a customer response to rates, education should help achieve a response to price signals in rates. In fact, CLECA *urged* "good marketing of and education about TOU rates, evaluation of customer responses to these rates, and analysis of customer response across all customers."²⁸ Indeed, CLECA posited that advanced metering infrastructure (AMI) data should be used in this process and "result in focus group studies of good and poor responders to determine what works and what does not."²⁹ CLECA concluded that the Commission could "learn from the current utility residential TOU pilots how customers respond and whether there are ways to make it easier for them to do so, such as through

²⁶ PD, at 12. The footnote, however, refers to the Joint DR Parties' comments, not CLECA's comments. The footnote should refer to CLECA's comments at pages 5 and 12-13.

²⁷ Comments of the California Large Energy Consumers Association Responding to ALJ Hymes' Ruling of May 20, 2016, at 5.

²⁸ *Id.*, at 12.

²⁹ *Id.*

technology.”³⁰ CLECA did not and does not downplay the impacts of education. The PD’s discussion in the text at page 12 should be revised as follows:

~~Downplaying the education efforts,~~ CLECA cautions that setting a goal for time of use rates may be difficult since customers will respond to rates as they do and CLECA opposes mandatory controls on customer usage; CLECA urges informed education efforts to hopefully impact customer responses to time of use rates, ~~with or without education.~~

III. CONCLUSION

CLECA appreciates this opportunity to provide comments on the PD and supports its adoption with the clarifications and modifications provided above.

Respectfully submitted,



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September 19, 2016

³⁰ Comments of the California Large Energy Consumers Association Responding to ALJ Hymes’ Ruling of May 20, 2016, at 13.

Appendix: Proposed Changes

Findings of Fact

37. A review of 2018 demand response program applications for current demand response programs should be routine and the utilities should include proposed replacement programs for the Demand Bidding Program.

40. It is unknown whether the CAISO market will be ready to integrate the newer model demand response programs, as the ongoing work on integration of existing supply side demand response has demonstrated.

45. ~~Many parties were in general agreement regarding~~ agreed on the need for one goal for both load modifying demand response and supply side demand response.

52. Demand response programs of the investor owned utilities and third-party demand response programs should be on a level playing field.

New FOF 73: Currently, there is insufficient information to conclude whether the demand response auction mechanism has met its objectives.

86. The obligation to accept all complying bids up to the simple average August capacity bid price may ensures the auction mechanism provides a substantial growth opportunity for performance based demand response, but there may also be some valid gaming concerns as well as bid viability concerns.

87. Limiting procurement to the simple average August bid price may encourages competitive bidding behavior but may also lead to gaming and bid-to-win not bid-to-build.

93. The CAISO market price will determine whether a demand response resource bid into the market will be dispatched.

Conclusions of Law

7. Fossil-fueled topping cycle CHP facilities should be included in the list of prohibited resources.

8. It is reasonable to exclude **energy storage**, bottoming cycle CHP and pressure reduction turbines from the list of prohibited resources ~~used during demand response events, in return for an incentive.~~

Delete COL 9 if energy storage is included in COL 8,

12. The Commission should require non-residential customers to electronically attest to whether they own a prohibited resource and a) agree not to use the prohibited resource to reduce load during a demand response even in return for an incentive or b) if the prohibited resource is required to be used for safety, health, environmental or equipment or process protection reasons, agree to a default adjustment that ensures the use of the prohibited resource does not receive an incentive.

Ordering Paragraphs

Ordering Paragraph 3: Beginning on January 1, 2018, the following list of resources are prohibited to be used for load reduction during demand response events in return for an incentive: distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas, in topping cycle Combined Heat and Power (CHP) or non-CHP configuration. The following resources are exempt from the prohibition: pressure reduction turbines and waste-heat-to-power bottoming cycle CHP ~~stand-alone~~, as well as storage and storage coupled with renewable generation that meet the relevant greenhouse gas emissions standards adopted for the Self Generation Incentive Program.

Ordering Paragraph 13(b) The Utilities are not obligated to procure over 400 megawatts ~~gigawatts~~ each for PG&E or SCE, or 200 megawatts ~~gigawatts~~ for SDG&E.